

*Assessing Market Acceptance and Penetration
for Distributed Generation in The United States*

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Joe Iannucci and Jim Eyer

Distributed Utility Associates

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Executive Summary

The Distributed Utility Concept Overview

The Distributed Utility (DU) concept involves use of “distributed resources” (DRs). DRs are modular power technologies that provide power and/or energy when and where needed, often beyond and/or connected to the electric utility’s electricity distribution system. These DRs may be distributed generation (DG), energy storage (DS), geographically targeted demand side management and/or energy efficiency, or combinations thereof.

There are strong indications that utilities, their customers, and even their competitors (energy services providers or ESPs) will use DRs to reduce cost and/or for energy services that a traditional electric utility could not or would not provide. If so, there are potentially significant implications for the power and energy markets.

Scope and Approach

The goal of this effort is to enable the U.S. Department of Energy (DOE) to consider those implications in the U.S. as part of the National Energy Modeling System (NEMS), in support of related policy and regulation development. This effort characterizes a phased approach to development of a NEMS methodology to address DRs. Specifically this project provides bases—data and rationale—for an initial phase and it lays groundwork for development of more robust and more comprehensive evaluation techniques that will be needed as expected growth in use of distributed resources materializes.

Report Content

For phase one, a description of the recommended market evaluation methodology is provided along with a description of and values for data necessary to do that evaluation. The report also includes a discussion of key modeling issues and challenges related to both methodology and data, present and future.

Section 1. Introduction

The Distributed Utility Concept Overview

The Distributed Utility (DU) concept involves use of “distributed resources” (DRs)—modular power technologies that provide power and/or energy when and where needed, often beyond and/or connected to the electric utility’s electricity distribution system. These DRs may be distributed generation (DG), energy storage (DS), geographically targeted demand side management and/or energy efficiency, or combinations thereof.

Utilities can use DRs to 1) reduce operational costs associated with fuel purchases and O&M, and/or 2) delay, reduce, or eliminate the need for central generation, transmission, and distribution infrastructure. In other words if a utility can use a DR to serve new customer loads then the utility avoids incurring costs associated with elements of its traditional “central generation and wires” solution—historically the solution that utilities would use when DRs were not an accepted alternative.

Utilities can also use DRs to provide “value-added” services to specific areas within its service area or to specific customers. Such value-added services might include electric service with very high reliability or especially electric service with good quality.

In addition to utility use, energy customers may install DRs to: a) reduce overall energy costs—what the authors refer to as bill management—and/or b) provide elements of electric service not available from the utility, such as ultra high electric service reliability, high quality power, or heat.

Project Goal and Objectives

Given those premises and emerging trends in the electricity marketplace, there are strong indications that utilities, their customers, and even their competitors (energy services providers or ESPs) will use DRs to reduce cost and/or to provide “energy services” that a traditional electric utility could not or would not provide. If so, there are potentially significant implications for the power and energy markets.

The goal of this effort is to enable the U.S. Department of Energy (DOE) to begin to consider those implications in the U.S. as part of the National Energy Modeling System (NEMS), in support of related policy and regulation development. This effort initiates a phased approach to developing the NEMS framework for evaluating the DR marketplace. As such, the report also provides initial groundwork for development of more robust and more comprehensive evaluation techniques that may be needed as expected growth in use of distributed resources materializes.

Project Scope and Approach

For this project Distributed Utility Associates (DUA) documented: 1) a description and prioritization of criteria and data required to evaluate market potential for DG use (i.e., “market factors”), 2) values for key quantitative/economic market factors, 3) an overview of viable distributed resource options between the years 2000 and 2010, 4) generic cost and performance for distributed generation between the years 2000 and 2010, and 5) modeling issues and recommendations.

Section 2. DG Market Factors

Generic DG Market Factors

In simplest terms a utility will use a DR to serve a given load (existing or new) if, based on a comparison between the cost for DR and cost for the traditional utility infrastructure upgrade, the DR cost is lower. The portion of the total/technical market potential for which DRs are cost-competitive is the *economic market potential*. Estimating the actual portion of that economic potential that will be realized with any degree of accuracy is much more challenging and requires many assumptions, a complex dataset and a detailed evaluation methodology.

Electric Utility “Market Drivers”

The analytical methods they use can only address the electric utility’s economic perspective, usually assuming utility ownership. Currently, most utilities have limited incentive or even have *disincentives* to either 1) adopt unconventional or “unapproved” technology or innovative solutions, or 2) to reduce capital investments. Conversely, one attractive facet to utility use of the DU concept is that DRs can result in better overall capital asset utilization (of the utility infrastructure as a whole) leading to lower utility cost (and presumably price) and a higher return on investment.

One factor having a dramatic effect on DU market development is the regulatory whirlwind in the electric utility industry, including increased emphasis on competition. An example of a significant regulation-related driver of electric utility interest in and use of DRs is performance based ratemaking (PBR). PBR directly rewards “economic efficiency” associated with optimal use of the utility infrastructure. In theory it is technology-neutral allowing for use of DRs *and* conventional solutions, to minimize cost and to maximize benefits. DRs can be an important way for electric power distribution planners and engineers to accomplish this benefit/cost optimization by providing a means to maximize utilization of capital equipment as well as a way to improve service quality and reliability. PBR could tip the scales substantially in the direction of the DR solution in many situations.

Other drivers will eventually come from outside the traditional electric utility industry. For example, natural gas utilities may attempt to increase fuel cells by promoting natural gas fueled DRs. DR vendors may increase efforts to sell their equipment. ESPs may use DR’s as a key element in broader offerings, such as shared savings contracts. DRs may even be an important facet to local economic development.

Market Potential

Note that for the first phase in the NEMS DR evaluation effort, DUA recommends assuming that the total/technical market potential is equivalent to load growth, rather than the entire load or even replacements of retired equipment. That recommendation is based on the following premises:

- 1) it is unlikely that DRs will be used in lieu of most conventional system equipment replacements or upgrades, especially in the 2000 – 2005 timeframe.
- 2) even more doubtful is use of DRs utilities to replace existing equipment that still has a useful life.

Utility Avoided Generation, Transmission, and Distribution Capacity Cost

A key benefit associated with utility-owned DRs is that they provide “capacity” (in units of kiloWatts) that would otherwise be provided by central power generation plants and electricity transmission and distribution equipment.

In short, DR capacity is installed by utilities if the DRs cost is less than the electric utility’s “avoided cost” associated with otherwise needed improvements to their electric generation and/or transmission and/or distribution infrastructure (equipment). To the utility the net benefit is the degree to which DR cost is lower than this avoided cost for capital equipment that would be needed to provide service if the DR were not installed.

Note also that even if a central/grid based option is merely *deferred*—rather than being avoided entirely—the time value of money and in the future even the avoided financial risk associated with uncertainty about how much the new *central-based* option would be used can be significant. This “deferral benefit” alone may make the DR solution worthwhile to use, perhaps as a temporary installation, if the DR is redeployable.)

To the extent that the utility’s electric utility rates/prices reflect avoided (or deferred) costs in an “economically efficient” way, customers can “internalize” those benefits. Historically most or all electric utility customers are charged the average cost for the utility’s infrastructure. If future electric tariffs reflect the actual customer-specific costs (rather than average cost) then many customers and electric utilities will have a significant economic incentive to use DRs that does not exist today.

DR Operational Modes—Peaking and Baseload

Not all DR applications and technologies are the same. To assess the market for DRs to the first order requires, separate evaluation of two distinct DR applications: *peaking* and *baseload* generation. The distinction is important because the characteristics of peaking and baseload DRs are different as are the economic incentives and decision criteria used to evaluate the relative merits of DRs for peaking and for baseload uses.

Peaking DRs operate during the utility’s peak demand hours--the hours during the year when demand for electricity is highest and when cost to produce, transmit, and deliver additional electricity is highest. Peaking DRs operate for just enough hours of the year so utilities can avoid the need for and cost of additional utility equipment/infrastructure traditionally used to satisfy demand for power (i.e., for “capacity” to generate and/or deliver electricity). “Avoided” equipment may include power generators, transformers, and wires that *would* be needed to meet the last increment of peak demand (usually occurring for only a small portion of the year) if the DR were not used.

Baseload DRs operate for thousands of hours per year—to meet typical loads a utility plant would operate from about 4,000 – 8,700 “full load equivalent” hours per year. Assuming they operate during the utility peak demand hours, baseload DGs receive the capacity credit ascribed to peaking resources. But, for baseload DRs also very important to consider cost-of-production for electric energy when evaluating the DR’s competitiveness--because they operate for many hours per year they must also compete on an “energy cost” basis.

DG Technology and Fuel Options

As noted above, for the first phase DG market evaluation early adopters are assumed to be electric utilities, to meet the opportunities and challenges in the new energy marketplace. That assumption is made because, for the next several years, utilities are expected to be by far the most likely parties to have both: 1) clear financial incentive to use DRs (to reduce cost), and 2) wherewithal to evaluate, design, and perhaps most importantly to finance DR projects. (Even if this is not a valid assumption, market estimates made using this techniques will still be sound because non-utility stakeholders that would install DRs would do so in response to price that, to one extent or another, and for the foreseeable future, reflects utility cost.)

Furthermore, it is assumed that: a) most distributed resources will be generation (DG) options, b) most DGs will be fueled with natural gas, and c) a significant minority of DGs will use Diesel fuel.

Given those assumptions, for the first phase of the NEMS/DR effort criteria and data documented address the needs for a market evaluation of natural gas fueled DGs, from the electric utility perspective, for electric utility “internal” uses within its infrastructure. Such an evaluation would be based solely on economic criteria that electric utility planners and engineers would use to evaluate costs and benefits associated with use of DGs.

Note that renewables such as solar and biomass were not addressed, nor were non-generation DR options—geographically targeted conservation/energy efficiency, demand side management (DSM), and energy storage. However, these options may eventually be economical—in some or even many situations—and thus would compete against generation options.

Customer Electric Reliability Requirements and Electric Utility Service and DG Operational Reliability

Currently and to a greater extent in the future, customers’ electric reliability requirements will be a key criterion affecting decisions about use of DRs. Consider electricity users needing superior electric reliability for high-value-added operations. If the utility service is reliable enough and price is acceptable then customers are likely to be satisfied with utility service.

However, if the utility service is not reliable enough then several scenarios could arise. Among them,

- the utility may decide that the cost, hassle, or risk is too high or the utility could decide that they do not have an obligation to serve the customer or that they do not have an interest in meeting the customer's extra reliability requirements,
- the utility could use the conventional "wires" solution or it could install a DR within its infrastructure, at or near the customer's site. If the utility can charge a premium for the enhanced reliability commensurate with added costs—for wires or for DRs—then they may undertake the project,
- the customer may purchase or contract for on-site back-up generation and/or UPS capacity.

Evaluating the options (for increasing electric reliability) will become important for all stakeholders as use of DR increases, though tools to undertake the analysis are limited. Traditionally utilities have had limited options to consider. Customers may have had more options but were not well equipped to evaluate and/or to operate them. Today DGs, other DRs, other technologies, and growing competition within the electricity and energy services industries are all leading to many new viable means to address electric customers' reliability needs.

Models, methodologies, tools, and data needed to evaluate the options in a credible manner will have to be developed. Key criteria affecting the decision about which option to use in a particular situation include:

- 1) the specific reliability needs of customers and perhaps even specific loads on the customer's premises, present and future
- 2) an understanding of the cause of unacceptable electric grid reliability and the cost—initial and ongoing—for necessary improvements using conventional utility means and DR options,
- 3) the reliability of DRs that may be used in lieu of the wires solution

Fuel Availability and Delivery Reliability

Another critical facet to DG market development is availability of fuel, capacity to deliver fuel, and operational reliability of the fuel delivery system. This is especially compelling for natural gas about which some important uncertainties exist. For example, if too many natural-gas fired DGs are installed for a given natural gas pipe then some obvious problems can arise, ranging from gas pressure that is too low for all customers to severe damage to pipes and compressor equipment and service curtailments. Another consideration is the dynamics of a marketplace where DGs proliferate rapidly, competing for fuel supplies that may not keep pace and/or that may not grow in an orderly fashion. Conversely, some DGs can use a range of fuels; so they can burn alternatives—usually petroleum distillates—during shorter duration disruptions in the supply/delivery of the primary fuel.

DR-related Hassle

Several factors related to DR siting and operation could be so expensive or require so much time and effort that the expense and/or nuisance are significant enough to jeopardize DR installations, particularly for generation. This is especially true if related costs or compliance requirements change frequently or ex post facto. Some or all of the following could contribute: and use permitting and regulations, building and electrical codes, fire and safety compliance, fuel storage and procurement, addressing localized NIMBY reactions, air emission regulations compliance—state and local, utility electrical interconnection requirements, etc.

A development that could be an important market driver for baseload DG use would be an overhaul of local air regulations, building codes, land use rules and other permitting requirements related to DGs. Many are anachronistic; developed to regulate small numbers of distributed generators (mostly Diesel fueled back-up generation) or do not allow for DG at all. Ideally rules and regulations would be more transparent, streamlined and standardized. One emerging concept affecting DGs' prospects is "prequalification" of specific DG products/models. This would reduce some of the cost disadvantage that "small" scale DRs have relative to larger scale central/grid options.

Peaking-Application-Specific Market Factors

Utility-owned and operated peaking DRs must provide capacity during the utility's peak demand hours—times during the year when demand for electricity is highest and when cost to produce, transmit, and deliver additional electricity is highest. The most costly portion of peak demand—typically the 100 to 200 hours during the year when demand for electricity is greatest—is the target of peaking DRs.

The utility's high cost for capacity and energy during these hours is driven by two key factors:

- 1) central generation units that generate electricity during those peak demand hours have poor fuel efficiency and are expensive to start-up and to operate
- 2) financial returns are low for utility equipment that is utilized for only a small part of the year, such as transmission and distribution capacity installed just to serve loads during infrequent and short duration periods of peak demand.

Utility use of peaking/capacity DGs to meet incremental peak demand for electricity is an important concept for this evaluation. That because the degree to which a DR allows the utility to avoid installation of additional capacity (and thus the associated cost) constitutes a key economic benefit associated with DRs. Stated another way, to the extent that DRs operate so they offset the need for new/upgraded utility electric grid capacity, they should receive a "capacity credit" commensurate with the amount of otherwise needed utility generation, and/or transmission, and/or distribution equipment (capacity, infrastructure).

Note that because peaking DRs operate for so few hours per year their total variable operating cost is a relatively insignificant criterion in the evaluation despite having high incremental cost for each kWh produced.

The following is a prioritized list of market factors that are expected to affect the timing, size, and growth rate of the market for distributed generation as an electric utility peaking/capacity resource in the U.S. during the period 2000 - 2010. (Note that generic factors described in the previous section also apply.) A brief description of each is provided in the section above about generic DR market factors or in the discussion of peaking-specific market factors below.

- Utility Avoided Transmission and Distribution Capacity Cost
- Utility Avoided Generation Capacity Cost
- DG Installed Cost
- Customer Electric Reliability Requirements
- Electric Utility Service Reliability
- DG Operational Reliability
- DG-related Hassle
- DG Non-Fuel Operating Cost

Utility Avoided Generation, Transmission, and Distribution Capacity Cost

Please see the discussion of this subject in the generic DR market factors section.

Customer Electric Reliability Requirements and Electric Utility Service and DG Operational Reliability

Please see the discussion of this subject in the generic DR market factors section.

DR-related Hassle

Please see the discussion of this subject in the generic DR market factors section.

DG Installed Cost

Needless to say the cost to purchase and install DG's equipment is an important criterion affecting DR market development for utility peaking/capacity applications. Because they only operate for a small portion of the year, peaking DRs' equipment cost is spread over relatively few units of energy (produced) annually. This makes DR equipment cost an important, perhaps the most important criterion of merit—assuming the device does what is needed and that it may be permitted and sited where needed.

Equipment cost (per kilowatt of nameplate capacity) for leading peaking DGs is about the same as or somewhat more than cost for larger peaking generation plants. DG *installed* cost can easily be double the equipment cost, when adding: a) transaction costs associated with installation such as specialized engineering or onerous permitting and b) air emission related requirements—transactional and for equipment. So, even though peaking DG equipment cost is not a major hurdle to expanded use, there is a need to reduce non-equipment components of installed cost.

DG Non-Fuel Operating Cost

DG non-fuel operating cost—mostly variable, but including fixed—can be an important criterion affecting economic viability of specific DRs. First, cost for routine and emergency maintenance is likely to be higher (per unit of energy produced) for DGs than

for options with much larger scale. Second, transaction costs associated with owning and/or operating many small DRs are also likely to be higher per kWh produced than for larger-scaled “central” alternatives—especially if the DR requires on-site operators.

A fleet approach employed by utilities, ESPs, and even large customers to minimize DG non-fuel operating cost. Another possibility is to develop and deploy DGs whose design results in very limited wear and tear, to minimize variable maintenance costs. Sophisticated monitoring and control systems can minimize or eliminate the need for on-site operators.

Peaking Market Perspective

Market opportunities for peaking DRs and DGs are sizable and many are addressable now or in the near term. One high level study [Iannucci] undertaken by the Gas Research Institute (GRI) indicates that economic market potential rises from 8,000 MW per year to almost 15,000 MW per year between 2000 and 2010. By 2010 the same study projects that most U.S. electric load growth could be met economically by DG capacity. The market potential rises through the decade primarily because of the slow escalation of the ratio of central station generation avoided costs to its replacement costs and projected DG improvements. (The study gives no indication of the portion of the potential that will be served by DGs.)

It is clear that peaking DRs are competitive and that their competitiveness will improve. Given many peaking DG’s low installed cost—cost that is often lower than a utility’s cost for generation, transmission, and distribution capacity needed—DGs are often the best solution. Even when considering the economic externality value of the air emissions many existing DGs are cost-competitive for peaking applications. That because the small number of annual operation hours needed for the benefits (avoided cost) to accrue means that even a heavy penalty per kWh generated—such as the 8¢ for Diesel engines—the overall cost is lower than for the central utility option.

The existing market for back-up generation though much smaller than that for electricity as a whole, is mature and growing. That niche could be a very important market entry channel for DG into the broader energy marketplace. Existing and new back-up generation could be instrumented and interconnected with the electricity grid as a very low cost capacity addition.

Baseload-Application-Specific Market Factors

As described above, utility-owned baseload DRs generate electric energy for 4,000 – 8,700 full load equivalent hours per year, primarily to provide low/competitively priced energy. And, assuming that utility-owned baseload DGs operate during the utility’s peak demand hours, those same baseload DGs also receive the capacity credit for utility avoided cost associated with peaking DRs. So, baseload DRs are deployed by electric utilities for one or both of two primary benefits:

- 1) to avoid costs related to adding utility generation, transmission, or distribution equipment/infrastructure (i.e., capacity) and
- 2) to produce cost-competitive energy, primarily electric energy but possibly including mechanical and thermal energy—resulting in reduced overall cost-of-service, and possibly reduced net fuel use and net air emissions.

For electric energy baseload DG's competition is usually very low cost commodity electricity from the "central" electric marketplace dominated by large generation facilities with economies of scale, generally lower energy production cost/price, and often lower cost/priced supply capacity. So to be competitive, often utility-owned baseload DGs must provide capacity benefits such that their total benefits (energy and capacity) offsets the central market's energy cost/price advantage.

Therefore, installed capital cost and cost-of-production are both key criteria driving a baseload DR's economic competitiveness. A baseload DR's marginal cost-of-production is mostly a function of: a) fuel efficiency, b) fuel price, c) variable operations and maintenance costs, and d) the economic value of heat from CHP operation (if any).

The following is a prioritized list of market factors that will have a significant impact on the timing, size, and growth rate of the market for baseload distributed generation by U.S. utilities for the years 2000 - 2010. A brief description of each market factor is provided; either in the section above addressing generic DR market factors or in the descriptions of baseload-specific DG market factors below.

- DG Fuel Efficiency
- DG Fuel Price—relative to alternatives
- Utility Avoided Transmission and Distribution Capacity Cost
- Utility Avoided Generation Capacity Cost
- Air Emissions--Net
- DG Installed Cost
- Customer Electric Reliability Requirements
- Electric Utility Service Reliability
- DG Operational Reliability
- DG Non-Fuel Operations Cost
- DG-related Hassle
- DG Fuel Availability and Delivery Reliability
- Combined Heat and Power (CHP) Value, if applicable

DG Fuel Efficiency and Fuel Price

Because they operate for so many hours per year, for baseload generators in general to be economically viable their incremental energy production cost must be competitive with alternatives. Fuel cost is by far the largest component of incremental energy production cost for most DGs and central generators. Fuel cost is a function of fuel efficiency and delivered fuel price.

Note that though DGs often have fuel efficiency that is competitive (plus they allow electric utilities to avoid electric transmission and distribution energy losses), they usually must use higher priced fuel. That is true because plant scale and thus purchase volumes are smaller so commodity prices and related delivery and transaction costs are higher per unit of fuel delivered. Depending on who purchases the gas and in what volumes price will range from somewhat above prices paid for whole sale/pipline quantities to retail for medium to large gas customers.

Baseload DG market-makers—utilities or ESPs—may be able to achieve better economies of scale by taking a fleet approach to managing regional DGs.

Utility Avoided Generation, Transmission, and Distribution Capacity Cost

Please see the discussion of this subject in the generic DR market factors section.

Air Emissions—Net

One key benefit associated with many DRs and DGs is that they emit fewer pollutants per kWh produced than do central generation plants, especially coal fired ones. In some cases DGs with low emissions may be the only acceptable option. However, more often the ability for DR owners to internalize benefits associated with low emissions is limited. In fact, often, DGs must meet more stringent or onerous air emission regulations than central generation sources. Because baseload DGs operate for so many hours per year and despite the current situation with regard to permitting of DGs and the inability to “monetize” benefits associated with fewer air emissions this is becoming an important market factor.

For air emissions to become an important market driver it will be important for DGs’ air emissions to be viewed in the context of total air emissions from all generation rather than permitting DG’s in isolation based on the DG’s incremental contribution to local pollution. In other words though use of DGs in lieu of more polluting central generation may result in less overall pollution, DGs are permitted with consideration given mostly to localized effects including their entire contribution to pollution rather than the net amount resulting.

Also important for baseload DG market development are means and mechanisms for DR owners to internalize benefits associated with clean DRs’ air emission advantages. These could include, for example, reduced air permitting costs, tax advantages, or air emission credits.

DG Installed Cost

Baseload DG purchase and install costs comprise a significant portion of total lifecycle cost. However, because they operate for a large portion of the year, baseload DRs’ equipment cost is spread over many units of energy (produced) annually. This makes baseload DGs’ equipment cost a somewhat less important criterion than it is for peaking DRs.

Like peaking DRs, equipment cost (per kiloWatt of nameplate capacity) for leading baseload DGs is similar to that for large-scale baseload generation plants, especially when including new coal fired central power plants; so equipment cost is not a key hurdle to more use by utilities. Also like peaking DGs, baseload DG *installed* cost is often somewhat higher than that for central plants when adding costs for specialized engineering or construction, onerous permitting or air emission related permitting and equipment.

Note that fuel cells, an important new baseload DG technology, cost two to five times more than DG power plants using conventional generation technologies--reciprocating engines and combustion turbines. This equipment cost gap must be reduced before fuel cells can gain significant market share as a baseload DG option. Indeed, dramatic reductions are projected for fuel cell equipment cost.

Customer Electric Reliability Requirements and Electric Utility Service and DG Operational Reliability

Please see the discussion of this subject in the generic DR market factors section.

DG Non-Fuel Operations Cost

Please see the discussion of this subject in the generic DR market factors section.

For baseload DGs it is the variable costs that are important in most cases. Maintenance expenses related to plant wear and tear from operation usually dominate non-fuel operations cost. If applicable, labor cost for on-site operation is also an important element of DG non-fuel operating cost.

DG-related Hassle

Please see the discussion of this subject in the generic DR market factors section.

Permitting may be more challenging and most costly for baseload DG because environmental impacts—air emissions and sound—occur for so many hours per year.

DG Fuel Availability and Delivery Reliability

In addition to items discussed in the DG Fuel Availability and Delivery Reliability portion of the Generic DG Market Factors section above, expansion of the natural gas distribution infrastructure could be quite important for baseload DG market development because it would enable more potential DG locations. In fact increased use of DG, especially baseload DGs that operate for many hours per year, may be a key driver of natural gas distribution infrastructure expansion, especially if it is part of a gas company's overall strategy for growth.

Combined Heat and Power Operation

Most baseload DGs can provide useful/valuable thermal energy if “waste” heat from their operation is captured for processes or for space conditioning—a process called combined heat and power (CHP). For customers that use a lot of heat—especially industrial, institutional, and agricultural operations—CHP can improve the economics of specific

DG projects and/or reduce a facility's overall cost of energy considerably. For phase one this aspect of DR market evaluation is not addressed as it is a relatively small driver in an already small overall market (relative to the overall energy marketplace). Depending on the relative importance of CHP either to policy or to DR economics, it will probably have to be added as an evaluation criterion in the future.

Baseload Market Perspective

Based on a recent market estimate report by GRI [Iannucci] baseload natural gas-fueled DGs might not have a significant presence in the new electricity marketplace as quickly as peaking technologies. That is projected for two major reasons. First, most of the value of DG lies in its ability to clip local (T&D) and central (electric supply) demand peaks, thereby deferring expensive capital upgrades. Because central station energy costs are low in the off-peak period, it would take a very efficient DG unit to beat central station energy costs in the baseload mode. Second, baseload modular technologies have yet to reach their projected long-term cost and performance targets.

The most important technologies for baseload DG applications appear to be fuel cells (if cogen or environmental credits can be obtained) and small gas turbines. Gas turbines enter the market faster than fuel cells (since their costs are initially more attractive). By 2010, annual baseload DG installations could reach several thousand megawatts per year for any of the three technologies.

Section 3. Distributed Generation Technology Characteristics

Introduction

There are literally hundreds of DRs or combination of DRs that could be evaluated. Most DRs are/will be distributed generators (DGs) that convert liquid and/or gaseous hydrocarbon fuel into electricity. Most often the fuel used is natural gas with Diesel fuel used for a relatively small portion of DG. The most DG capacity (MegaWatts) will be comprised of combustion turbine generators, reciprocating engine generators, and fuel cells.

Before utilities will use DGs extensively for their own applications, DGs must have some generic features and characteristics and certain conditions must exist. Systems, parts, support, engineering, and service must be readily available. Cost-effective DGs must be available in a range of packages and sizes, must have "utility-grade" hardware and controls, and must have been proven to operate reliably, cost-effectively, and seamlessly with the electric utility distribution system.

Both peaking and baseload leading technologies are characterized in detail below; current and projected cost and performance estimates are provided:

- Electric utility owned peaking DGs provide electric capacity. To be competitive they must provide reliable capacity at a cost that is lower than the utility's avoided cost for the grid solution. A peaking DG's installed cost is usually the

key criterion of merit with operating costs being a secondary driver of overall economics. Several types of DGs can do that in many situations.

- Electric utility owned baseload DGs provide electric capacity and energy for many hours per year and may reduce utility peak demand. Cost-effectiveness may be driven by one or more of the following costs: Equipment, fuel, and non-fuel operation and maintenance. In most cases, baseload DGs must be more fuel efficient than the “next available” central energy source because smaller plant scale and smaller volume fuel purchases lead to higher fuel prices and transaction costs.

Generic Distributed Generation Technologies

For phase one modeling it is appropriate to minimize the distinction between individual DG technologies, primarily because the key objective of this work is to establish the appropriate evaluation technique and criteria, without undue regard to technology-specific characteristics. Furthermore, realistically the phase one evaluation cannot be precise, for many reasons including rapid changes in regulatory treatment instead it can really only indicate the overall significance of the market potential. Therefore, for the phase one evaluation two generic technologies—one peaking and one baseload—have been defined. As shown in Table 1, generic DG cost and performance values represent a composite of equipment in years 2000 and 2010.

Table 1 Generic DGs’ Fuel Efficiency, Variable O&M, and Installed Cost

Name	Generic--Peak		Generic--Baseload	
	2000	2010	2000	2010
Year Initially Available	2000	2010	2000	2010
Analysis Year	2000	2010	2000	2010
Typical Size (MW)	0.4	0.4	2.47	1.6
Construction Lead Time (years)	0.2	0.2	0.5	0.5
Overnight Costs - "initial" versions ¹	n/a	700	n/a	2000
Overnight Costs - nth (mature) ¹	531	440	591	560
Variable O&M (mills/kWh) ¹	23	15.5	15.05	10.4
Fixed O&M (\$/year, year one) ^{1,4}	\$12.5/kW-yr	\$12.5/kW-yr	\$4.0/kW-yr	\$6.3/kW-yr
Heat Rate (Btu/kWh _{HHV})	10,620	10,500	10,991	9,210
Fuel Cost Class ²	I,C,E	I,C,E	I,C,E	I,C,E
NOx Emissions (lbs/MMBtu _{in})	0.936	0.481	0.486	0.038
SOx Emissions (lbs/MMBtu _{in}) ³	0.013	0.010	0.001	0.001
Load Cycle (base, intermediate, peak)	peak	peak	base	base
Fuels Usable (may add cost) d--distillate/Diesel, el--electricity et--ethanol, H2--hydrogen me--methanol, ng--natural gas s--solar, w--wind	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng

Notes: ¹ \$1999 Constant.

² Most DGs can be used for industrial and commercial loads and in some cases residences, especially for "multi-unit dwellings."

³ Natural gas fired DGs emit negligible amounts of SOx.

⁴ Fixed cost for peak \$5,000/year, for baseload: \$10,000/year, mostly for annual safety and insurance inspections and for permitting

Specific Distributed Generation Technologies

Given the generic DG characteristics described in the Introduction portion of this section above, specific DG technologies selected as constituents of the composites in Table 1. DGs selected are either: 1) judged by DUA to be commercially viable, reliable, and serviceable, currently or within the evaluation time horizon or 2) emerging small power generation options (fuel cells) that have great promise as clean electricity sources within the evaluation window. Data for peaking and baseload DGs are shown in Tables 2 and 3.

Though many values are for mature technologies with known cost and performance data, values for newer, less tested options are best estimates. All are based on a broad array of information sources and necessarily reflect values from key entities and stakeholders reflecting several perspectives and a broad array of technology-biases. As a result there is a fair degree of judgement and interpretation required to establish these data. Data used is from publicly available documents from a broad array of organizations such as the United States Department of Energy (DOE), Electric Power Research Institute (EPRI), Gas Research Institute (GRI), Edison Electric Institute (EEI), and many DR vendors and electric and gas utility representatives.

Because much of the data changes so often—especially for emerging technology—it is usually best gleaned from current publications such as presentation material and papers from conferences. Other less timely data is gathered from reports and books. Please see the list of references for details.

Peaking DGs include low cost microturbines and frame type combustion turbines operating on natural gas, and three types of reciprocating engines: Diesel fueled, dual fueled compression ignition (requires 5% Diesel fuel for combustion and 95% natural gas), and spark ignited natural gas fueled.)

As indicated in the Technology Weighting—Portion of Composite data field for each peaking DG type in Table 2, Diesel fueled engines are most common in 2000 (40% of the composite), with frame CTs and dual fueled engines making up about 20% of the composite. Spark ignited engines make up most of the balance of the composite DG with only a small portion for microturbines.

In 2010 the portion of the composite plant that is from Diesel fueled engines drops from 40% to 30% of the total. Spark gas engines' portion of the composite drops from nearly 20% to about 10%. Microturbines make up most of the decrease—the 2010 composite peaking DG is 20% microturbine. Dual fueled engines still comprise 20% of the composite.

Diesel cycle/compression ignition engines, either operated with Diesel fuel or with natural gas (i.e., dual fueled) are perhaps the lowest cost distributed generation options, though significant deployment engines may be problematic because of air emissions.

**Table 2 Specific Peaking DGs' Fuel Efficiency,
Variable O&M, and Installed Cost**

Name	Microturbine--P		Frame Combustion Turbine--P		Diesel Fueled--P		Dual Fuel--P		Spark Gas--P	
Year Initially Available	2000		2000		2000		2000		2000	
Analysis Year	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010
Typical Size (MW)	0.25	0.25	1	1	0.25	0.25	0.25	0.25	0.25	0.25
Construction Lead Time (years)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Overnight Costs - "initial" versions ¹	700	n/a	700	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Overnight Costs - nth (mature) ¹	600	350	600	350	500	500	550	500	500	500
Variable O&M (mills/kWh) ¹	20	10	20	10	25	20	25	20	20	15
Fixed O&M (\$/year, year one) ^{1,4}	5000	5000	5000	5000	5000	5000	5000	5000	5000	5000
Heat Rate (Btu/kWh _{HHV})	13,000	12,000	11,500	11,000	10,000	9,500	10,500	10,000	11,000	10,500
Fuel Cost Class ²	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E
NOx Emissions (lbs/MMBtu _{in})	0.246	0.050	0.278	0.055	1.600	1.053	0.886	0.600	0.318	0.238
SOx Emissions (lbs/MMBtu _{in}) ³	0.000	0.000	0.000	0.000	0.030	0.030	0.003	0.003	0.000	0.000
Load Cycle (base, intermediate, peak)	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
Fuels Usable (may add cost) d--distillate/Diesel, el--electricity et--ethanol, H2--hydrogen me--methanol, ng--natural gas s--solar, w--wind	d, ng, me, H2	d, ng, me, H2	d, ng, me, H2	d, ng, me, H2	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng
Technology Weighting--Portion of Composite	1%	20%	20%	20%	40%	30%	20%	20%	19%	10%

Notes: see Table 1.

**Table 3 Specific Baseload DGs' Fuel Efficiency,
Variable O&M, and Installed Cost**

Name	Microturbine--B		Combustion Turbine--B Frame 2000 ATS 2010		Dual Fueled Engine--B		"Current" Fuel Cell--B		"Advanced" Fuel Cell--B	
Year Initially Available	2000		2002		1995		1998		2005	
Analysis Year	2000	2010	2000	2010	2000	2010	2000	2010	--	2010
Typical Size (MW)	1	1	4	4	1	1	1	1		1
Construction Lead Time (years)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5		0.5
Overnight Costs - "initial" versions ¹	700	n/a	n/a	n/a	n/a	n/a	3,000	n/a		?
Overnight Costs - nth (mature) ¹	700	400	500	400	650	600	2,000	1,000		600
Variable O&M (mills/kWh) ¹	20	10	10	7	20	15	15	10		10
Fixed O&M (\$/year, year one) ^{1,4}	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000		10,000
Heat Rate (Btu/kWh _{HHV})	12,500	11,300	11,500	9,500	10,500	10,000	8,600	8,000		7,500
Fuel Cost Class ²	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E	I, C, E		I, C, E
NOx Emissions (lbs/MMBtu _{in})	0.112	0.049	0.104	0.042	0.886	0.100	0.000	0.000		0.000
SOx Emissions (lbs/MMBtu _{in}) ³	0.000	0.000	0.000	0.000	0.003	0.003	0.000	0.000		0.000
Load Cycle (base, intermediate, peak)	base	base	base	base	base	base	base	base		base
Fuels Usable (may add cost) d--distillate/Diesel, el--electricity et--ethanol, H2--hydrogen me--methanol, ng--natural gas s--solar, w--wind	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng	d, H2, me, ng	d, ng, H2	d, ng, H2	H2, me, ng	H2, me, ng		d, H2, me, ng
Technology Weighting--Portion of Composite	1%	20%	49%	20%	49%	20%	1%	10%	0%	30%

Notes: see Table 1.

Baseload DGs include relatively efficient/heavy duty microturbines, combustion turbines (in 2000 typical frame type turbines and in 2010 the Advanced Turbine System, or ATS) operating on natural gas, dual fueled compression ignition engines (requires 5% Diesel fuel for combustion and 95% natural gas), and current and advanced fuel cell systems.

As indicated in the Technology Weighting—Portion of Composite data field for each baseload DG type in Table 3, combustion turbines and dual fueled engines dominate the composite baseload DG in 2000 (both make up 49% of the composite).

In 2010 the portion of the composite plant that is from dual fueled engines and combustion turbines drops from 49% in 2000 to 20% of the total each. Microturbines make up another 20% of the composite. Current fuel cell technology adds 10% to the composite while advanced fuel cells make up the balance.

Note that although dual fueled engines can provide cost-competitive baseload distributed generation (energy). Significant deployment of these engines may be problematic because of air emissions.

Section 4. Market Data and Evaluation: Issues and Challenges

Economic Market Potential Estimation

Phase 1 Modeling Approach Overview

To begin the process, first the utility cost to own and operate a DR (cost-of-ownership) is calculated, based on DG cost and performance assumptions. That cost-of-ownership is the net cost incurred to own and operate the DR; including purchase, installation, financing, depreciation expenses, taxes, fuel and maintenance costs, and fixed costs such as periodic overhauls and insurance.

The utility compares that DR cost-of-ownership to the utility's "avoided cost." In this case the cost avoided is the cost associated with the traditional utility central/grid infrastructure solution not installed if the DR is installed. That is the key utility-related benefit associated with use of the DR—the cost that will *not* be incurred by the utility. (Of course this assumes that the DR can provide the same or better service reliability and quality.) In other words, for the utility, the benefit associated with use of a DR is the avoided cost for otherwise needed fuel, O&M, and overhead expenses and generation, transmission, and distribution capacity (equipment) costs.

As discussed in Section 2 of this report, authors recommend that, for phase 1 of the evaluation, the maximum potential size of the market for DRs (also known as technical potential) is assumed to be proportional to the load growth—in units of MW. Note that this conservative definition of market potential means that DGs are not used to serve "embedded" load, nor are they used to offset retirements of a utility's existing capacity—they only have the potential to serve annual increases in electric demand (load growth). As the DU concept and DR solutions become more familiar to utilities and electric utility customers this assumption will have to be reconsidered.

Key Modeling Challenges

The approach described above is essentially a sophisticated cost-based evaluation. Furthermore it reflects an energy marketplace with only marginal DG deployment. Though appropriate as an initial step, clearly that will not suffice as DR use increases and as non-utility stakeholders enter the fray.

As DRs proliferate a whole range of incentives, issues and unexpected consequences will surface. Some may have to be taken into account to make a credible market projection. Among the identifiable modeling challenges are effects from

- the evolving level of electric utility industry interest in the DU concept, ranging from avoidance and creating hurdles all the way to active participation and encouragement.
- the gas industry's ability to deliver gas to small generators where and when needed especially at the high penetration levels possible.
- market forces that drive utilities to establish prices that more accurately reflect customer-specific avoided costs for generation and delivery of electricity, via performance based ratemaking or other competitive market mechanisms.
- the absence of established electric utility industry planning models which adequately account for benefit and cost tradeoffs between DG installations and installation of generation, transmission and distribution systems.
- evolving regulatory treatment of DR use, ranging from favorable or even of indifferent regulatory treatment of utility DU implementation by electric utilities, gas utilities, and/or ESCOs
- increasing use of DRs and DGs; effects could include, for example, DG-related 1) electricity "congestion" in power distribution systems, 2) impacts on electric service reliability, and 3) influences on natural gas prices, availability, and delivery infrastructure reliability.

In general, improved modeling of the DR market will require a much more sophisticated approach, possibly including "logic elements" such as those that evaluate

- DR dispatch regimes,
- DR technology-tradeoffs (initial and over time),
- DR capacity installation phasing,
- risk related to changed rules mid-stream for DR installations (e.g. air emission regulations get stricter),
- asset utilization and area-specific financial benefits associated with use of DRs,
- saturation of local electric and/or gas distribution capacity,
- customer diversity—by load and/or activity type
- customer preferences
- competition among DRs
- many others

DG Modeling Assumptions and Data Limitations

In addition to *modeling* challenges related to techniques and criteria, even if a good methodology is developed, getting some of the input data required to do the evaluation would be challenging. There are several reasons for this.

First, many data needed for a robust evaluation have not been important historically. As a result those data may be difficult to obtain or may not even exist. Other reasons that data may not be accessible include:

- 1) electric utility reluctance to reveal competitive disadvantages related to cost,
- 2) there may be no accepted/approved way to calculate values or there may be conflicting means to derive values for some criteria,
- 3) data may be in forms or locations that make it difficult to get.

Beyond challenges related to data *availability*, many existing energy and cost data affecting DR viability are based on a marketplace without significant DR presence. With methodology-related challenges noted in the description above, if DRs proliferate those data may change significantly, in ways and for reasons that are mostly unknown today.

Fuel Cost and Availability, Fuel Delivery Reliability

As described in Section 2, fuel price, availability, and delivery reliability (primarily for natural gas) are important facets to a robust DR marketplace. However the effect these have on the DR market and conversely the effect that a burgeoning DR market will have on those factors is largely unknown. That is a key challenge for future phases of DR/DG modeling in NEMS. For the period 2000 – 2005 it is assumed that DG market penetration will have only marginal effects on the natural gas supply and delivery infrastructure reflecting rapidly growing but still modest DG use. Customers purchase gas at normal retail rates and utilities' cost reflects wholesale prices plus delivery cost.

Transmission and Distribution Avoided Costs

Transmission and Distribution Avoided Costs

These data are very important for DG market development. Often they underlie the biggest or one of the biggest benefits associated with DRs and DGs. Unfortunately electric utilities' historical approach to tracking costs that getting this data is difficult. Under traditional ratemaking, utilities really only had to be able to calculate 1) average cost to serve broad customer classes and 2) total cost to serve all customers. As a result it may be difficult or even impossible to get detailed information about the range and variability of costs incurred, such as electricity distribution costs associated with narrow customer classes or among different areas or "area-types" within the utility grid.

Considering the difficulty associated with getting detailed avoided cost data, a high level estimation approach is recommended for phase 1. It is based on available information about utilities' or regions' T&D budgets and is developed using some general rules about variability. The recommended approach will provide sufficient accuracy for phase 1 and possibly even later phases of the NEMS DR market evaluation.

The following table, Table 4, shows the range of avoided costs for the average utility in the United States developed using the recommended approach. Note that these are for costs associated with added load—from electric load *growth*. The same data were developed for each of the NEMS EMM regions.

Table 4 U.S. Average T&D Avoided Costs

Growth-related T&D Cost <i>Bin Low</i> (\$/kW)	Growth-related T&D Cost <i>Bin High</i> (\$/kW)	Growth-related T&D Cost <i>Bin Average</i> (\$/kW)	Bin Frequency (%)	Cumulative Frequency (%)	Fixed Charge (annualization) Rate (%)	Annual Growth-related T&D Avoided Cost (\$/kW-yr)
0	125	62.5	0.0	0	0.12	8
125	375	250	33.9	33.9	0.12	30
375	505	440	31.8	65.7	0.12	53
505	631	568	18.1	83.8	0.12	68
631	838	734.5	11.0	94.8	0.12	88
838	995	916.5	3.2	98	0.12	110
995	1000	997.5	2.0	100	0.12	120

Electric Service Reliability Implications of DRs

Utility data about service outages is spotty, usually reflect imprecise and average values, mostly for electric supply-related and transmission-related outages. Beyond that electric service reliability and outage information can be very sensitive, because of legal liability, competition and several other considerations.

For initial efforts the benefit associated with DRs is calculated based on standard electric utility industry values for: 1) “loss of load probability” used to determine the number of hours per year that a customer may experience an outage and 2) “value of service” that indicates the monetary value associated with activities that customers cannot undertake because electric service was out. Well-established values are published for those criteria.

Variable O&M

Limited historical data is available for variable O&M costs associated with operation of DGs as envisioned under the distributed utility concept. Data for existing gen-set operation, including small portion that is grid connected is an important point of reference initially. As DG operating experience grows that data should be refined to reflect the new knowledge.

Baseload Scenario and Peaking Scenario Definitions

For the phase 1 “utility perspective” cost-based evaluation DUA recommends using the value of 200 hours as a representative value for peaking applications. Baseload operation is assumed to be added to meet typical utility loads that operate for about 52% of the year (full load equivalent).

In reality, of course, there are significant variations among utilities, regions, customer types and classes and even on individual electric distribution systems. Furthermore, other

stakeholders respond to electricity price (as opposed to utility cost) for electric demand and on-peak electric energy. So customers and ESPs operate based economic “signals” that are often different than those that an electric utility must respond to.

Furthermore, an owner will adjust a DR’s capacity factor in response to financial incentives, and possibly some less quantifiable criteria. When that occurs modeling of the overall marketplace for DRs may have to evolve to accommodate the phenomenon.

Future Considerations

- Alternative Modeling Perspectives: Customer, GASCo, ESP, Electric DISCO
- Market Potential: Load Growth versus Embedded Load
- Transmission and Distribution Avoided Costs
- Electric Service Reliability Implications of DR Use
- DG Load Factor
- DG/Backup Generation Synergies
- CHP
- End-user Diversity
- Unit Sizing Assumptions
- Market Saturation
- Renewables, Storage, and EE/DSM DRs
- Emissions Modeling
- Location Types—Substation and Feeder

Alternative Modeling Perspectives: Customer, GASCo, ESP, Electric DISCO

The phase 1 NEMS DR evaluation emphasizes the utility perspective, both because utilities have the best technical expertise, capitalization, and ability to internalize benefits. However, as the electricity marketplace becomes more competitive others will also have the means to internalize the same benefits, especially if the utility avoided costs are reflected in tariffs in an economically efficient way—via rates and price signals that reflect costs.

Customers are most eager to minimize their energy costs and related hassles. DRs are used if they reduce expenses for or to generate revenues from electricity generation and thermal energy. Gas companies want to sell more gas. ESPs are out to participate in energy “projects” for profit. Electric distribution companies may want to reduce cost and/or to improve returns on distribution equipment assets.

Modeling individual perspectives alone may be challenging enough considering factors such as a) energy-related customer preferences and b) different though interrelated economic incentives for various stakeholders. Even more difficult is modeling of a) interactive effects between DR stakeholders, and b) DRs’ interaction with the overall energy marketplace.

Market Potential: Load Growth versus Embedded Load

For subsequent phases of the NEMS DG evaluation effort, the assumption about electric load growth being the total/technical market potential will have to be evaluated as the internalizable economic incentives for various stakeholders come to the fore.

For example, depending on electricity and fuel prices it may actually be economical to use DG in lieu of existing electric utility assets, even if those assets have to be retired prematurely. Another factor is competition—as it increases a downward pressure on electricity prices is likely such that DGs may be cost-effective for electric demand beyond just new load. DG technology improvements may reduce cost to the point where DGs are cost-effective for large segments of the electricity marketplace. That too would affect the assumption about technical market potential. (Not that estimating the total/technical market potential is much different though closely related to estimating actual market levels; the latter being the portion of the technical potential that will be realized.)

Transmission and Distribution Avoided Costs

As noted above, detailed/area-specific T&D avoided cost data is difficult to obtain and is likely to remain that way for most of the decade from 2000 – 2010, for historical reasons related mostly to electric utility bookkeeping and financing techniques, and for emerging reasons related to competitive advantage in the new electricity marketplace. Therefore, the same high level estimation approach recommended for phase 1 should be used for subsequent phases, until superior information becomes available.

But, to one extent or another competition and/or deregulation in the electricity marketplace of the future will force disclosure of transmission and distribution avoided costs, probably as “price signals.” Once that occurs a more robust approach to modeling market response may be warranted.

Electric Service Reliability Implications of DR Use

Under competition, presumably electric utilities will (or will be required to) share historical data about outages and will gather and publish more technical and financial data about service outages.

Ideally data would be very customer-specific and would ultimately indicate the economic cost associated with electric service disruptions. In reality it can probably only be specific to customer-classes, hopefully narrowly defined, and can only give an *indication* of the order-of-magnitude of the reliability benefit.

When that information becomes available, the economic reliability improvement possible from DRs—including consideration of the DR’s reliability and availability—can and perhaps should be calculated more precisely for the market as a whole. In reality, though, this criterion may be somewhat difficult to generalize as it may be quite customer or customer-type-specific.

DG Load Factor

Though for the phase 1 NEMS DR market evaluation DGs are defined as serving peaking or baseload needs, in reality once a DG or other distributed resource is installed its capacity factor will be adjusted as economic incentives and operational conditions change. Furthermore, motivations affecting DG capacity factor vary among: a) stakeholders especially electric and gas utilities, energy customers and ESPs, and b) specific installations/locations. Thus the struggle over how, where, and by whom implementation of the DU concept occurs may involve capacity factor and the ability to dispatch and control DRs.

Customers are most eager to minimize their energy costs and related hassles. That may include use of DRs to reduce expenses for or to generate revenues from electricity generation and thermal energy. The desire to minimize the total energy bill drives decisions about capacity factor. For example, if a customer can trade-off gas use for electricity or vice versa to minimize costs that is what she will do. Initially at least electric utilities will be most comfortable with low capacity factors; with peaking DGs used to clip local demand peaks (and possibly “system” peaks) without impacting revenues appreciably. Gas utilities will want baseload operation, to maximize gas sales. ESPs want to maximize profit, market share and service contracts, leading them to want relatively high capacity factors.

An electric utility adjusts a DR’s capacity factor in response to changes in demand for electricity, amounts and timing. In some situations evolving customer electricity demand patterns may lead to the need for higher DG capacity factors. Units may have to operate as “intermediate-load” resources operating for several hundred to about 2000 hours per year. However, intermediate capacity factors may not be best accomplished with the peaking DR technology that was installed initially (and evaluated as part of this initial analysis). Specifically intermediate-load operation may require better fuel efficiency, better “load following” capability, different unit sizes to be optimal or even cost-effective.

Given the possibility that many peaking DGs may need to be upgraded to provide intermediate or even baseload service, it is important to note that many types of peaking DG units that utilities are likely to install in the near term for peaking applications would have significant salvage value or better yet would be moved to other locations requiring low capacity factor service. Thus the modularity, portability, and ease of installation of DG resources may be very important for future phases of the evaluation.

For the initial evaluations addressing peaking DGs, the ability to relocate DGs is important because it is likely that a utility-owned DG that can be moved easily will be used for most or all of its useful life. So even if specific/local conditions change such that specific peaking DGs are no longer suitable (e.g. for intermediate load operation) it is reasonable to assume that the peaking DG will probably be re-used at another site. Furthermore, some peaking DGs can be used seasonally—to meet summer demand in one location and then to meet winter demand at another.

The ability to accommodate a range of capacity factors using DGs leads to an interesting possibility for the gas industry's DG market entry strategy. It may be important for the gas industry to offer peaking units (perhaps via ESCO subsidiaries) as a way to establish a large strategic DG market share of low capacity factor units. These units could be installed soon, and operated at low but increasing capacity factors. During the next ten years the baseload technologies such as fuel cells will improve, electric utility's generation avoided costs may rise, and the electric utility industry will establish performance based rates and DU policies. Once it is opportune for baseload market entry, the low capacity factor units can be replaced with more efficient and environmentally acceptable baseload units based on advanced technologies such as fuel cells or gas turbines (e.g. the Advanced Turbine System, ATS, developed in cooperation with the U.S. DOE).

Perhaps by as early as 2005 the electric utility industry will be ready to accept the higher capacity factor DG installations, which will consume much more natural gas. That acceptance by the electric industry coupled with gas vendors' desire to sell more gas and to increase utilization of the gas T&D infrastructure would seem to be a significant development for a burgeoning DG market.

ESPs add another interesting perspective affecting the future of DG capacity factor and thus natural gas consumption. Aggressive ESPs may be willing to offer customers packaged DG technologies as a way to reduce overall energy bills in exchange for "shared savings." Some local gas distribution companies may choose to become full-fledged ESPs and/or to partner with electric utilities to provide economically optimized DRs or DR-related services.

DG/Backup Generation Synergies

Though the DU concept is new there are actually many hundreds of MegaWatts of existing back-up generation capacity in the United States; and a growing amount is added each year. Activation of this existing back-up generation capacity, is, in many cases, the lowest incremental cost source of electric capacity. If utilities or others can find means to both 1) operate those generators as if they were utility resources/capacity and 2) internalize benefits associated with those back-up generators beyond the reliability boost they give (to the actual load served) then the existing back-up generators may become the first big block of DG capacity added to the grid system.

CHP

Most baseload DGs characterized for this study are assumed to be capable—technically—of providing thermal energy via combined heat and electric power (CHP, also known as cogeneration).

For baseload DGs DUA assumes that the incremental cost associated with adding equipment needed for CHP is \$280 per kW. That extra cost (over and above that for a non-CHP DG plant) is mostly for piping, heat exchangers, and engineering associated with gathering, moving, and storing waste heat from/during operation of the prime mover.

At present, DUA assumes that 15% of all new load is coincident with thermal loads such that a DG with CHP capability could be used to serve electric and thermal loads. All baseload DRs are assumed to have enough waste heat for CHP.

In a practical sense CHP can only occur at feeder locations—at or near the location where electric demand and thermal loads are. (Please see the subsection of this report entitled Location Types—Substation and Feeder, below).

End-user Diversity

The phase one approach does not allow for consideration of the diversity of customers that may or should be interested in DRs. For example using DG could improve customer reliability that is very beneficial for some high-value-added businesses but not for residences or normal commercial or institutional loads. There is also the possibility that some larger, more institutional customers will use distributed resources to “bypass” their electric utilities or to minimize their electric demand charges whereas these are not as compelling to smaller customers.

Unit Sizing Assumptions

Historically central generation’s power production cost advantage relates mostly to economies of scale associated with the large size of central plants. Conversely one advantage to DRs is their modularity. This allows important flexibility to respond as DG-project-specific capacity requirements change and it reduces financial risk associated with less scalable, less redeployable assets such as distribution wires and substations. Modeling the market and economic impacts of this feature/characteristic of DGs will become more important in the future; though for NEMS the effect is likely to be modest.

For the phase 1 evaluation DGs are assumed to be quite scalable. In reality they come in discreet sizes although there is quite a range of sizes available depending on DG type and vendor. In the future NEMS may have to treat this aspect of DR evaluation more carefully. As an example, if on paper a class of small commercial facilities are assumed to have sufficient economic incentive to use a given DG, if that DG cannot be purchased in a size that is consistent with those facilities’ power needs then technically the projects may never come to fruition.

Market Saturation

For initial phases of the NEMS DR market assessment, because there really is so little existing DG capacity that “market saturation” is not an important criterion. However, that could change as the market grows. Saturation can be caused by a number of supply/demand criteria such as 1) there is already “enough” DG in a given power distribution area or even a regional power supply to meet capacity and/or energy needs, 2) the power transmission and/or local power distribution system cannot handle additional DG capacity, 3) the natural gas supply and/or transmission and/or distribution systems cannot serve additional DG capacity, 4) local or state officials will not permit additional DRs for a variety of reasons including land use/siting and air quality.

Renewables, Storage, and EE/DSM DRs

Phase 1 of the NEMS DR market estimation includes consideration of only distributed generation using natural gas or Diesel fuel. In the future many expect other DR technologies to be important too:

- **renewables** could include engines, combustion turbines, or fuel cells operated on biogas or hydrogen fuel, small wind turbines, and the most likely renewable DR, photovoltaics, especially building integrated versions.
- **energy storage** such as electrochemical batteries, superconducting energy storage (SMES), flywheels, and ultracapacitors
- **geographically targeted energy efficient loads and demand-side-management**

These technologies are not addressed in the phase 1 evaluation for a variety of reasons, key among them are: 1) fuel systems to produce, transport, or store gaseous renewable fuels and hydrogen are still being developed, 2) most renewable power plants are still too expensive for most grid-connected applications, 3) some renewables are not “dispatchable” (i.e. they operate when the resource is available, not necessarily when needed), and 4) modeling for these technologies’ economics and operation is quite complex.

Green Power

An emerging driver for use of renewables and clean energy resources in general and probably distributed renewable generation specifically is the advent of green power programs whereby utilities offer electricity produced using clean/renewable energy resources. As this niche grows and matures consumer preference for green energy may become an important criterion driving demand for clean energy at the wholesale level and for distributed renewables generation and geographically targeted energy-efficient loads for more localized applications.

Emissions Modeling

Capturing the effects of air emissions (and other “external” or environmental impacts) on the relative competitiveness and attractiveness of DR options requires a special evaluation. That involves economic market estimates made without and with monetized values for environmental externalities associated with both DR operation and operation of central/grid-based resources providing the same level of service.

To undertake such an evaluation first DR options are evaluated for economic competitiveness (relative to central/grid-based solutions) without regard to air emissions. Then economic market potential is estimated given an economic value (or in effect a penalty) assigned to each unit of pollution for air emissions of interest. Those emissions penalties (expressed as \$ per unit of pollution) are applied to air emissions from DRs and to air emissions from central generators that they would displace. DRs are then compared to the central/grid solution given: a) traditional equipment, fuel and operation costs plus b) those monetized externalities—the economic value/penalty ascribed to air emissions.

Location Types—Substation and Feeder

As depicted graphically in the Figure just below, it may be desirable in future phases on the NEMS DG/DR effort to make a distinction among DR projects installed at two location types: 1) a utility substation upstream from some or all affected customers, and 2) on a distribution feeder at or near affected customers' sites.

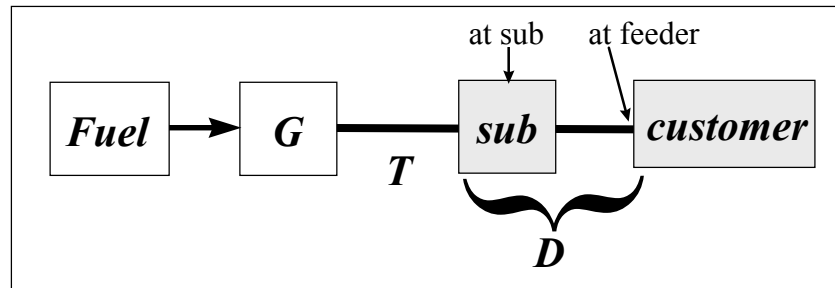


Figure 1 DUVal Evaluation Nodes

Several factors distinguish these two types of locations. Most important is that because most electric service outages occur between the substation and the load the DR at the substation does not receive as substantial a credit for reliability increases as does a DR located on the feeder or at the customer's site. DR's at substations do not defer the need for a feeder and thus do not receive an avoided cost credit for the cost of a feeder. DR's at the substation are assumed to be larger and are assumed to qualify for purchase of gas procurement price reflecting wholesale/power plant-scale bulk purchases whereas DR's on the feeder are assumed to use gas whose prices are higher as purchases are at a lower volume/"retail" level. An implicit assumption is that the required fuel (type of fuel and fuel distribution infrastructure) is available at all sites considered.

One implication of the need for low fuel prices to make baseload applications economically viable is that baseload DRs tend to be deployed almost exclusively at substation locations. That is due to the fact that natural gas price is assumed to be significantly higher for feeder locations than for substation locations, for a variety of reasons. Note also that the fuel price advantage at substation locations can be offset, to some degree, by the fact that DRs located at substation locations are farther from loads than feeder DRs (i.e., are upstream from most outages) and thus DRs at substations provide much less reliability improvement (benefit) than do those downstream.

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